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REAL-WORLD TECHNOLOGY TESTS

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Testing offshore technology—onshore

RMOTC has simulated the sea floor to test a hydraulic pumping system.

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The Rocky Mountain Oilfield Testing Center (RMOTC) recently extended its capacity to provide real-world environments for testing new oilfield technology by simulating a sea-floor environment. At Naval Petroleum Reserve No. 3 (NPR-3), RMOTC created a testing environment equivalent to 3,000 ft of water depth at its large-bore test well facility, to test a hydraulic pump for deep-sea use.

Oilwell Hydraulics Inc., in association with an Australia-based company, tested one of its hydraulic pumps at RMOTC's facility. Hydraulic pumping systems transmit power downhole by means of pressurized power fluid that flows in wellbore tubulars. The downhole pump acts as a transformer to convert the energy of the power fluid to pressure in the produced fluids. The pump tested was designed to run at a maximum capacity of 13,440 bpd, greater than what was available off the shelf and therefore physically larger than existing equipment.

Located almost 1,000 mi inland near Casper, Wyoming, NPR-3 bears no resemblance to an offshore environment on the surface. But with the help of RMOTC and Oilwell Hydraulics staff, NPR-3 was transformed to simulate the environment where the pump would eventually be used—the Perth Basin offshore Australia. Additional testing at the facility could be altered to mirror other sub-sea conditions worldwide to test offshore technology including submersible pumps, swab equipment, plunger lift equipment, gas lift equipment and mud drilling fluids.

The site for testing the pump needed to have control of both the power fluids and the produced fluids downhole. The wellbore diameter needed to accommodate the larger pump and the fluid tubulars. No existing wellbore at RMOTC would fill the requirements, so a new, large-diameter well was

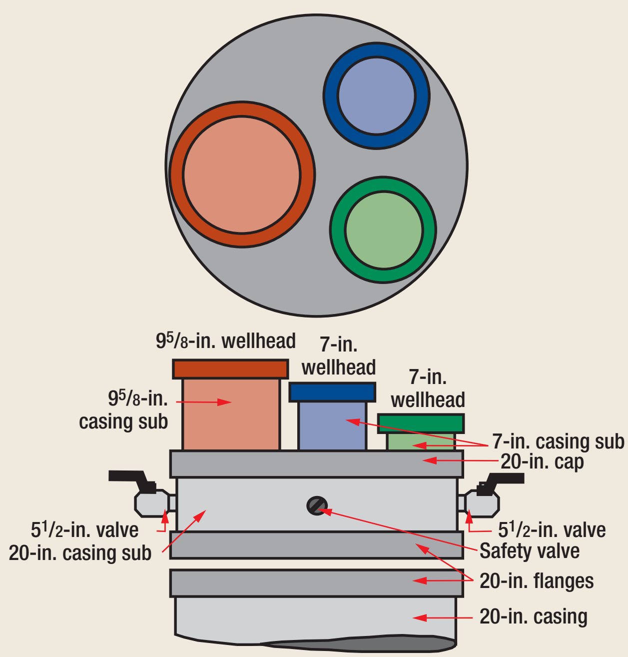

Fig. 1. Wellhead schematic showing the two 4½-in. casing strings and one 5½-in. casing string inside the 20-in. casing.

Fig. 2. A special wellhead was designed for the 20-in. casing with 5½-in.-thick flange to fit over the 198-ft hole.

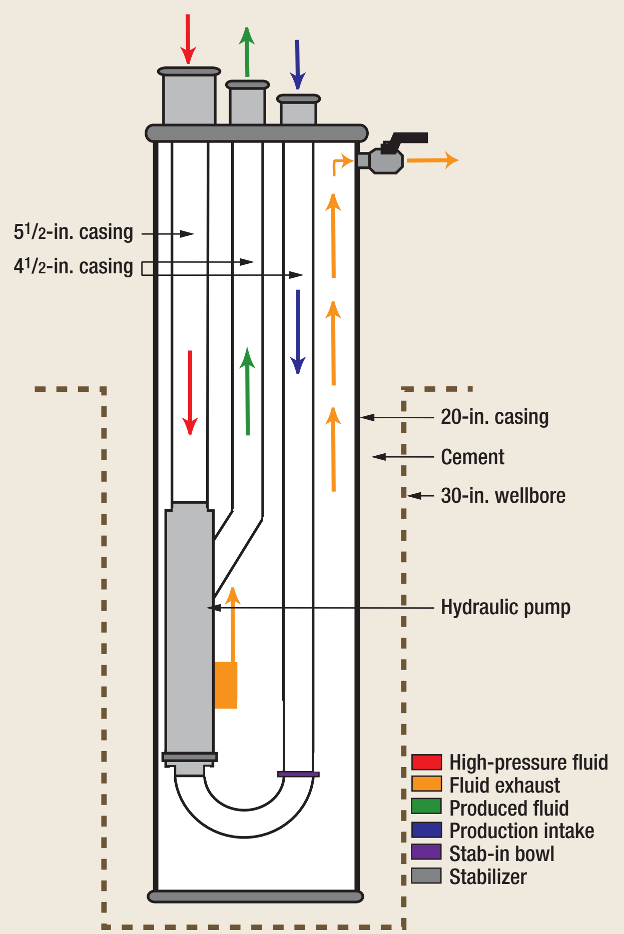

Fig. 3. In the pump test, the 5½-in.-OD casing was the inlet for power fluid. The second-tallest wellhead was an outlet for the returned produced fluid, and the shortest was the inlet source for the produced fluid.

drilled at a site chosen by RMOTC engineers. The site is adjacent to a water-treatment plant that provided a water source and storage facilities.

The primary objectives for this test were:

- To quantify the downhole pump efficiency
- To confirm that the pump could be deployed and retrieved hydraulically
- To determine the extent of wear and/or damage sustained by the pump.

Testing was completed in two stages, the first stage running for 11 days and the second stage for 18 days.

METHODOLOGY

The large-bore test-well facility has a 20-in. casing set at 198 feet and cemented to the surface. Inside the 20-in. casing are two strings of 4½-in. casing and one string of 5½-in. casing, Fig. 1. A special wellhead was designed by an RMOTC engineer especially for the site and pressure tested to 1,400 psi, Fig. 2. The 20-in. casing used is 94-lb/ft, K-55, buttress thread, which has an internal pressure rating of 2,110 psi. The wellhead has a 5½-in.-thick flange to fit on the 20-in. hole. Each of the three casing strings run has its own wellhead equipped with a safety valve, as well as two 5½-in. valves on the sides. The wellhead flange is attached to the 198-ft hole by 20 bolts.

Fig. 4. Color-coded piping at the test well.

The 5½-in.-OD casing, which formed the tallest wellhead, was used in the pump test as the inlet source of the power fluid. The second-tallest wellhead was used as an outlet for the returned produced fluid, and the shortest wellhead was used as the inlet source for the produced fluid. A 5½-in. valve on the side of the wellhead was the source of returned power fluid. Power fluid left the bottomhole assembly downhole, where it then traveled up the annulus and was circulated to the power fluid tank, Fig. 3.

A color-coding system was devised to indicate directional flow of fluid through the system, Fig. 4. Pipes carrying fluid to the surface plunger pumps from the tanks were painted yellow. Inlet pipes to the wellheads, including the high-pressure power fluid and the produced supply line, were painted red. Produced fluid and returned power fluid were delivered in pipes painted blue. All tubing was labeled with tape indicating the direction of flow.

To measure the volumetric and pressure conditions, the test circuit included four flowmeters to record the volumes displaced and five pressure gauges. The system efficiency was then calculated directly from the flowrate, pressure and manual stroke counts. Any changes were then evaluated to determine if there was a loss of efficiency or a measurement error.

The system was run at several different flowrates so that friction losses could be calculated. During this process, the system did not exceed a pressure of 500 psi. Once the friction losses were calculated, an extended run was done at 1,000 psi to calculate the efficiency of the pumps and motors. Fluid loss was also calculated, and observations were taken to determine whether there was a fluid exchange between the power fluid side of the system and the produced fluid.

Two 5,000-bbl water tanks were used to test the hydraulic pumps. During the first stage of testing, only one tank was used as a source of both power fluid and produced fluid, since it was not necessary to differentiate between the two fluids in this stage. Differentiation was needed for the second stage, so for that stage, both tanks were used. By checking the tank levels, it was possible to identify any fluid exchange between parts of the system.

It was important to simulate produced water from the reservoir in the Perth Basin where the pump would be used primarily. For the first stage, this was accomplished by adding

Fig. 5. The bottomhole pump being laid down after testing.

calcium chloride. Near the start of the test, the power fluid's chlorides were raised from 1,040 ppm found in the Tensleep supply water to 2,240 ppm, according to a sample taken four days after the test began. Before the second stage of the test, sodium bicarbonate was also added to the power fluid tank. Specific measurements were developed to simulate real produced water and to minimize damage to the pump.

RESULTS

Vibration and pressure surge affected flowmeters and pressure gauges during the test, thereby affecting the results of the pump efficiency calculations. Better stabilization of piping and placement of gauges were evaluated and will help to minimize these issues in future testing. The final objective of this test was to successfully retrieve the pump. Key to widespread utilization of the pump is the ability to consistently deploy and retrieve it hydraulically. Although the test well at the RMOTC facility is shallow and vertical, successful hydraulic retrieval established that the method could be employed viably in deeper wells, Fig. 5. Following retrieval in the first stage, the pump was inspected for wear and tear, and corrosion and some scale formation was found. A chemical program was developed to protect the pump during the second stage, and no damage or scale formation was reported after inspection.

CONCLUSIONS

RMOTC will continue to pursue projects simulating offshore scenarios. In coming months, the facility will be used for lithologic calibration of an acoustic well-stimulation tool. The large-bore test well is available for additional test partners to design a sub-sea operating environment appropriate for technology testing. In addition to the facility described, RMOTC has another large-bore well with 17½-in. casing set at 1,200 ft.

For a full report on the test conducted, or for more information on RMOTC's test facilities, visit www.rmotc.com. **WO**

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